BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

DOCKET NO. 2019-185-E
DOCKET NO. 2019-186-E

In the Matter of:	)	
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South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	)	**DIRECT TESTIMONY OF GLEN A. SNIDER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

I. INTRODUCTION AND PURPOSE

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Glen A. Snider. My business address is 526 South Church Street, Charlotte, North Carolina 28202.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am currently employed by Duke Energy as Director of Carolinas Integrated Resource Planning and Analytics.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES IN YOUR POSITION WITH DUKE ENERGY.

A. I am responsible for the supervision of the Integrated Resource Plans ("IRPs") for both Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, "Duke" or the "Companies"). In addition to the production of the IRPs, I have responsibility for overseeing the analytic functions related to resource planning for the Carolinas region. Examples of such analytic functions include unit retirement analyses, the analytical support for applications for certificates of environmental compatibility and public convenience and necessity for new generation, and analyses required to support the Companies' avoided cost calculations that are used in the biennial avoided cost rate proceedings.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. My educational background includes a Bachelor of Science in mathematics and a Bachelor of Science in economics from Illinois State University. With respect to professional experience, I have been in the utility industry for over thirty years. I started as an associate analyst with the Illinois Department of Energy and Natural Resources, responsible for assisting in the review of Illinois utilities' integrated resource plans. In 1992, I accepted a planning analyst job with Florida Power Corporation and for the past eighteen years have held various management positions within the utility industry. These positions have included managing the Risk Analytics group for Progress Ventures and the Wholesale Transaction Structuring group for ArcLight Energy Marketing. Immediately prior to the merger of Duke Energy Corporation and Progress Energy, I was Manager of Resource Planning for Progress Energy Carolinas.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes. I have testified before the Commission on a number of occasions, most recently in DEP's 2019 fuel factor proceeding, Docket No. 2019-1-E.

Q. ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes, I am sponsoring three exhibits, which are described below:

- **Snider DEC Exhibit 1 (Confidential)** presents the supporting calculations used to derive the avoided energy and avoided capacity rates. Information included in this exhibit is designated Confidential and is being filed under seal.
- **Snider DEP Exhibit 1 (Confidential)** presents the supporting calculations used to derive the avoided energy and avoided capacity rates. Information

included in this exhibit is designated Confidential and is being filed under seal.

- **Snider DEC/DEP Exhibit 2** presents the information contained in Figure 3 and Figure 4 in a larger format for readability purposes.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR AT YOUR DIRECTION AND UNDER YOUR SUPERVISION?

A. Yes. These exhibits were prepared by me or at my direction and under my supervision.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to support the Companies' methodology for calculating avoided capacity and avoided energy costs, and other recommendations related to the Companies' payments to qualifying facilities ("QFs") pursuant to South Carolina's implementation of the Public Utility Regulatory Policies Act of 1978 ("PURPA") as recently addressed in the South Carolina Energy Freedom Act of 2019, ("Act 62" or "the Act"). More specifically, my testimony provides recommendations relating to the fair and appropriate calculation of avoided capacity and avoided energy costs used to compensate QFs under the Companies' Standard Offer Purchased Power Tariff ("Standard Offer Tariff" or "Schedule PP"). The Companies' methodology for calculating avoided costs for QFs eligible for Schedule PP will also be used to establish the avoided cost rates available to larger QFs, consistent with the Act. My testimony also addresses certain other aspects of the Companies' PURPA implementation framework under Act 62, such as the requirement to assess the cost of ancillary services provided by or consumed by small power producer QFs, including QFs utilizing energy storage.

My testimony is organized into the following sections:

I. Introduction and Purpose;

II. Overview of PURPA and Act 62 Avoided Cost Framework;

III. Description of the Peaker Methodology used to Calculate Avoided Costs under PURPA;

IV. Avoided Capacity Cost Calculation and Rate Design Methodology;

V. Avoided Energy Cost Calculation and Rate Design Methodology; and

VI. Integration Services Charge.

II. OVERVIEW OF PURPA AND ACT 62 AVOIDED COST FRAMEWORK

Q. HOW DOES THE DEFINITION OF AVOIDED COST IN ACT 62 ALIGN WITH THE GENERAL REQUIREMENTS OF PURPA?

A. As explained in greater detail by Duke Witness George Brown, the State's new PURPA administration and implementation framework established under Act 62 does not materially change the long-established requirements to quantify the Companies' "avoided costs" under PURPA. Act 62 defines "avoided cost" as:

> . . . the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.[1]

This is precisely the same definition prescribed by the Federal Energy Regulatory Commission's ("FERC") implementing regulations,[2] which were first adopted in

[1] S.C. Code Ann. § 58-41-10(2).
[2] 18 CFR 292.101(b)(6).

1980 in the FERC's PURPA rulemaking order, Order No. 69.[3] As explained in greater detail by Duke Witness Brown, PURPA limits the rates to be paid to QFs to the purchasing utility's "incremental cost of alternative electric energy," which is the utility's cost of electric energy which, but for the purchase from the QF, the utility would generate or purchase from another source.[4] This is known as the utility's "avoided" cost, and reflects PUPRA's foundational requirement that purchasing QF power at the utility's avoided cost, if accurately quantified, ensures customers remain indifferent between the costs of utility or non-utility generation.

Q. PLEASE EXPOUND ON PURPA'S PRINCIPLE OF CUSTOMER INDIFFERENCE AND NONDISCRIMINATION FOR PURCHASES FROM QFs.

A. Section 210 of PURPA rests on the twin pillars of nondiscrimination and customer indifference. Specifically, Section 210 of PURPA requires that the price paid by utilities for "must take" purchases of QF output be "just and reasonable to the electric consumers of the electric utility and in the public interest, and not discriminate against qualifying cogenerators or qualifying small power producers."[5] FERC has confirmed the need to ensure customer indifference to utility purchases of QF power, stating that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives."[6] Thus, the

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[3] *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978, Order No. 69*, at 12,216-7, FERC Stats. & Regs. ¶ 30,128 (1980) ("Order No. 69").
[4] 16 U.S.C § 824a-3(b); (d).
[5] 16 U.S.C. § 824a–3; PURPA, Sec. 210(a) (2005).
[6] *Southern Cal. Edison Co., et al.*, 71 FERC ¶ 61,269 at p. 62,080 (1995), overruled on other grounds, *Cal. Pub. Util. Comm'n*, 133 FERC ¶ 61,059 (2010).

"must purchase" obligation under PURPA requires utilities to offer to purchase QF power at "just and reasonable" rates that result in customer indifference as to whether the energy purchased is generated by the utility's generating fleet or purchased from the QF's generating facility pursuant to PURPA. Overall, these twin pillars promote fairness in the marketplace toward both QFs and the Companies' customers. In my view, setting avoided cost rates that achieve the customer indifference standard prescribed by PURPA will also effectuate Act 62's requirement for the Commission to "treat small power producers on a fair and equal footing with electrical utility owned resources."[7]

Q. PLEASE DESCRIBE HOW THE COMPANIES INTERPRET THE DIRECTIVE FROM ACT 62 THAT REQUIRES THE COMMISSION'S DECISIONS TO STRIVE TO REDUCE THE RISK TO CONSUMERS.

A. Section 58-41-20(A) of Act 62 specifically provides that "[a]ny decisions" by the Commission addressing PURPA implementation in South Carolina must "strive to reduce the risk placed on the using and consuming public." As discussed by Duke Witness Brown, this is a critically important objective for the Commission to consider as it reviews the Companies' updated avoided cost rates and policies under South Carolina's new PURPA implementation framework set forth in the Act. In my view, this express policy directive requires the Commission to achieve the customer indifference and nondiscrimination objectives discussed above, while also minimizing the potential for future over-payment and reliability risks being

[7] S.C. Code Ann. § 58-41-20(B).

imposed upon the Companies' customers that ultimately pay the costs of PURPA implementation.

Q. DOES ENCOURAGEMENT OF QF TECHNOLOGIES UNDER PURPA AND ACT 62 SUPPORT SETTING AVOIDED COST RATES AND POLICIES THAT SUBSIDIZE RENEWABLE SMALL POWER PRODUCERS?

A. No. PURPA encourages QFs by obligating utilities (and by extension, customers) to purchase QFs' output—at the QFs' option—at the utility's full avoided cost. However, Congress was clear that PURPA was not intended to require the utility and ratepayers of a utility to subsidize QFs.[8] As Duke Witness Brown explains, Act 62 prescribes South Carolina's implementation and administration of PURPA and should not be implemented in a manner that violates Congress' original intent in enacting PURPA. Recommendations that may be raised in this proceeding advocating that the Commission should subsidize or advantage QFs beyond ensuring customer indifference would violate Act 62 and be inconsistent with PURPA.

III. DESCRIPTION OF THE PEAKER METHODOLOGY USED TO CALCULATE AVOIDED COSTS UNDER PURPA

Q. PLEASE COMMENT ON THE REQUIREMENT IN ACT 62 DIRECTING THE COMMISSION TO REVIEW AND APPROVE THE COMPANIES' AVOIDED COST METHODOLOGY.

[8] Joint Explanatory Statement of the Committee of Conference, H.R. Conf. Rep. 95-1750 at p. 89, 95th Cong., 2d. Sess. 99 (1978) ("The provisions of [section 210] are not intended to require the rate payers of a utility to subsidize cogenerators or small power producers.").

A. As I explain above, Act 62 does not modify the foundational requirements of PURPA established by Congress and defines avoided cost consistently with FERC's implementing regulations. However, the General Assembly has directed the Commission to review and approve the Companies' methodology used to quantify its avoided cost offered to QFs under both the Standard Offer as well as to larger QFs above the 2 megawatt ("MW") Standard Offer eligibility threshold.[9] Act 62 also requires the Companies' avoided cost methodology to

> ". . . fairly account [] for costs avoided by the electrical utility or incurred by the electrical utility, including, but not limited to, energy, capacity, and ancillary services provided by or consumed by small power producers including those utilizing energy storage equipment. Avoided cost methodologies approved by the commission may account for differences in costs avoided based on the geographic location and resource type of a small power producer's qualifying small power production facility."[10]

In this section of my testimony, I introduce the Companies' use of the peaker methodology and the underlying theory and history of the peaker methodology. Then, in Sections IV and V, I provide a more detailed explanation of how the Companies implement the peaker methodology to quantify the Companies' avoided capacity and avoided energy costs and to develop avoided capacity and avoided energy rates paid to QFs. Finally, in Section VI, I respond to the specific consideration of ancillary services identified by the Act by introducing the Companies' proposed solar Integration Services Charge.

[9] S.C. Code Ann. § 58-41-20(A).
[10] S.C. Code Ann. § 58-41-20(B)(3).

Q. WHAT METHODOLOGY DOES DUKE USE TO CALCULATE AVOIDED COSTS?

A. DEC and DEP have consistently used the "peaker methodology" to forecast the Companies' avoided cost of capacity and energy in order to set the avoided cost rates paid to QFs.

Q. HOW DOES THE PEAKER METHODOLOGY WORK?

A. The peaker methodology is designed to determine a utility's marginal capacity and marginal energy cost, and therefore, can be applied to quantify a utility's avoided costs for purposes of pricing power purchases from QFs. This approach assumes that when a utility's generating system is operating at equilibrium, the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") generating unit (a "peaker") plus the variable marginal energy cost of running the system will produce a reasonable proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. Consistent with PURPA, the peaker methodology is designed to ensure that purchases from new QF generators are not more expensive than the avoided capacity cost of a peaker plus the utility's forecasted avoided system marginal energy cost.

Q. PLEASE DESCRIBE THE DIFFERENCE BETWEEN AVOIDED ENERGY COSTS AND AVOIDED CAPACITY COSTS UNDER THE PEAKER METHODOLOGY.

A. Avoided energy costs represent an estimate of the variable operating costs that are avoided and would have otherwise been incurred by the utility but for the purchase from a QF. Avoided energy costs, which are expressed in dollars per megawatt hour ("$/MWh"), include items such as avoided fuel, avoided variable environmental costs and avoided variable operations and maintenance ("VOM") costs. The peaker methodology approximates a utility's avoided energy cost through estimates produced by generation production cost modeling. Avoided capacity costs, on the other hand, represent fixed costs associated with the construction, financing and staffing of a CT facility. These fixed costs are not dependent on the actual use of the CT but rather the costs to build the CT and have it available to meet customer demand. As an analogy, if one was to purchase an electric vehicle, the avoided gasoline and avoided oil changes of a gas-powered vehicle would be the equivalent of avoided energy costs, which include avoided fuel costs and VOM. In addition, to the extent the electric vehicle offsets the purchase of a gas-powered vehicle, the car payment for the gas-powered vehicle would represent the fixed cost being avoided in the capacity payment and would be the equivalent of the avoided capacity cost.

Q. DOES THE PEAKER METHODOLOGY ALLOW THE COMPANIES TO FAIRLY AND APPROPRIATELY CAPTURE AND ESTIMATE THEIR AVOIDED COSTS THAT WOULD HAVE OTHERWISE BEEN INCURRED BUT FOR THE PURCHASE FROM THE QF?

A. Yes. The peaker methodology provides an appropriate and reasonable estimate of the avoided or incremental costs of alternative capacity and energy that would have otherwise been incurred but for the purchase from a QF facility. Importantly, it appropriately captures all avoidable marginal capacity and energy costs (or avoidable capital and operating costs) that consumers would otherwise pay "but for" the purchase from the QF. As such, the peaker methodology appropriately leaves the consumer indifferent to the utility's required purchase of QF generation relative to the utility's own generation.

Q. IS THE PEAKER METHOD A WIDELY-ACCEPTED METHODOLOGY IN THE UTILITY INDUSTRY FOR CALCULATING AVOIDED COSTS?

A. Yes. The Commission has consistently accepted the Companies' use of the peaker methodology to quantify DEC's and DEP's forecasted avoided capacity and energy costs. The Companies have also consistently utilized the peaker methodology in North Carolina, with the North Carolina Utilities Commission ("NCUC") finding that the peaker methodology is "generally accepted throughout the electric industry to calculate avoided costs."[11] The National Association of Regulatory Utility Commissioners ("NARUC") has also recognized the peaker methodology as one of the "dominant methodologies for measuring avoided cost under PURPA," which NARUC has further characterized as "well-developed for some time."[12] The peaker methodology is additionally recognized as an acceptable method for determining avoided cost in the *PURPA Title II Compliance Manual* recently

[11] *See Order Setting Avoided Cost Inputs*, at 30, NCUC Docket No. E-100, Sub 140 (Dec. 31, 2014) (Stating that the NCUC "has long approved the use of the peaker method for the purpose of establishing avoided costs and has repeatedly held that, according to the theory underlying the peaker method, if the utility's generating system is operating at the optimal point, the cost of a peaker (a CT) plus the marginal running costs of the generating system will equal the avoided cost of a baseload plant and constitute the utility's avoided cost.").

[12] Technical Conference on Implementation Issues Under the Public Utility Regulatory Policies Act of 1978, *The Honorable Travis Kavulla President, National Association of Regulatory Utility Commissioners, and Vice Chairman, Montana Public Service Commission June 29, 2016*, FERC Docket No. AD16-16-000 (2016) (citing to Robert E. Burns & Ken Rose, "PURPA Title II Compliance Manual" (March 2014) ("PURPA Title II Compliance Manual"), available online at: https://pubs.naruc.org/pub/B5B60741-CD40-7598-06EC-F63DF7BB12DC).

published by NARUC, the Edison Electric Institute and other industry organizations in 2014.[13]

Q. DO THE COMPANIES RECOMMEND THE COMMISSION APPROVE THE CONTINUED USE OF THE PEAKER METHODOLOGY TO CALCULATE DEC'S AND DEP'S AVOIDED CAPACITY AND ENERGY COSTS FOR BOTH THE STANDARD OFFER AND FOR AVOIDED COSTS AVAILABLE TO LARGER QFs NOT ELIGIBLE FOR THE STANDARD OFFER?

A Yes.

IV. AVOIDED CAPACITY COST CALCULATION AND RATE DESIGN METHODOLOGY

Q. IN GENERAL TERMS, HOW ARE AVOIDED CAPACITY COSTS CALCULATED UNDER THE PEAKER METHODOLOGY?

A. The peaker methodology credits avoided capacity value to the QF based on the utilities' cost to construct a simple-cycle CT. These costs represent the fixed capital, financing and fixed operating costs associated with the construction and operation of a CT facility. The fixed investment costs are then converted to an annual cost that includes both the recovery-of and return-on the investment in the CT, along with the annual fixed operating costs, such as staffing. This annual avoided capacity cost is then used to derive a levelized annual value for the number of years in the fixed term rate. Once determined, this annual value is then allocated

[13] PURPA Title II Compliance Manual, at 35.

to the seasons of the year, converted to a $/kW value and spread to the eligible capacity payment hours as defined in Schedule PP. The resulting avoided capacity credit is expressed in cents per kilowatt-hour ("kWh"). As I noted in the analogy of the QF as an electric vehicle, the avoided capacity cost is the annual car payment for the avoided gas-powered vehicle along with other fixed costs such as taxes.

Q. HOW SHOULD THE AVOIDED CAPACITY COST CALCULATION METHODOLOGY BE APPLIED TO ENSURE CUSTOMERS ARE NOT PAYING MORE FOR QF CAPACITY THAN THE ACTUAL COSTS THAT THE UTILITY AVOIDS FROM SUCH A PURCHASE?

A. The Companies rely upon several key elements in the application of the peaker methodology to most accurately align the avoided capacity cost rates that customers ultimately pay with the actual value of the capacity. These elements include: (a) calculating the annual avoided capacity value of a CT; (b) determining the first year in which the Companies actually have an avoidable capacity need; (c) determining how annual capacity payments are made to the QF supplier; and (d) applying an appropriate Performance Adjustment Factor ("PAF"). I describe each of these factors in more detail below.

Q. DID THE COMPANIES CALCULATE THE ANNUAL AVOIDED CAPACITY VALUE OF A CT FOR PURPOSES OF DETERMINING THE AVOIDED CAPACITY VALUE TO BE PROVIDED BY A QF?

A. Yes. DEC and DEP each calculated their respective avoided capacity cost based on the cost of constructing combustion turbine capacity. Data from the Energy Information Administration ("EIA") was used as the basis for developing the CT capital cost.[14] The EIA data reflects the cost to build a single CT unit at a greenfield site. Given that the Companies' practice is to build multiple units at a new site, the Companies adjusted the EIA data to reflect the economies of scale associated with land, buildings, roads, security, gas interconnection and other infrastructure for a 4-unit CT site.

Q. HOW DOES THE UTILITIES' NEED FOR INCREMENTAL GENERATING CAPACITY IMPACT THE CALCULATION OF THE AVOIDED CAPACITY PAYMENT?

A. As a central tenet of PURPA, customers should not be required to pay QFs for avoided capacity unless the QF is actually offsetting a capacity need of the utility. Accordingly, the annual fixed capacity costs used in the avoided cost rate calculation includes the annual fixed capacity costs starting with the first year in which an actual avoidable capacity need exists, as determined by the utilities' IRPs.

Q. HOW IS THE INTEGRATED RESOURCE PLAN UTILIZED TO DETERMINE WHEN AN AVOIDABLE CAPACITY NEED EXISTS?

A. The IRP is an extensive annual planning effort which presents a 15-year resource plan that identifies when the next generating unit is needed in order to maintain reliable electric service into the future. Prior to the year in which the next avoidable generation unit is needed, the utility does not have a capacity need to avoid, and

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[14] *See* U.S. Energy Information Administration, Office of Electricity Coal, Nuclear and Renewable Analysis, *Cost and Performance Characteristics of New Generating Technologies*, *Annual Energy Outlook 2019* (January 2019), *available at https://www.eia.gov/outlooks/aeo/assumptions/pdf/table_8.2.pdf.* (last visited Aug. 13, 2019).

therefore in the calculation of the capacity rate, no value for avoided capacity is ascribed in these years.

Q. IN WHAT YEARS DO THE COMPANIES' INTEGRATED RESOURCE PLANS IDENTIFY THE FIRST AVOIDABLE CAPACITY NEED?

A. DEC's projection of its first avoidable capacity need arises in 2026, while DEP's first avoidable capacity need is 2020. The Companies' projection of their respective first years of avoidable capacity need are consistent with the Companies' upcoming 2019 IRP Update filings. For comparison, DEC's first year of need (2026) arises two years earlier than the prior projection in its most recently filed 2018 IRP, which will increase the avoided capacity rates relative to relying upon the prior 2018 IRP. DEP's identified year of need (2020) is the same year of need as identified in the 2018 IRP.[15]

Q. DOES ACCOUNTING FOR THE TIMING OF NEEDED CAPACITY MORE ACCURATELY VALUE THE CAPACITY BEING DELIVERED BY THE QF, CONSISTENT WITH THE INTENT OF PURPA?

A. Yes. PURPA's clear intent is to estimate the costs that, but for purchase from the QF, would have otherwise been incurred by the utility and its customers. Let's assume that weak economic conditions result in flat or declining load combined with a large influx of QFs that have eliminated all future needs for the addition of fossil generation capacity. In such an example, incremental QFs would still be credited for avoiding marginal fuel and production costs based on the utility's

[15] *See* Duke Energy Carolinas, LLC 2018 Integrated Resource Plan, at 66 Docket No. 2018-10-E (filed Aug. 31, 2018) ("DEC 2018 IRP"); Duke Energy Progress, LLC 2018 Integrated Resource Plan, at 64 Docket No. 2018-8-E (filed Nov. 1, 2018) ("DEP 2018 IRP").

generation fleet (avoided energy value); however, incremental QFs would not receive a credit for avoided capacity because there would be no fixed costs to offset or avoid as the utility would not have a need to construct new generating capacity to reliably serve its customers. Under those circumstances, crediting a QF for avoiding a non-existent future capacity need would clearly be inconsistent with PURPA. PURPA's principle of customer indifference between the cost of new utility capacity and QF purchases requires the recognition that if the utility's first avoidable capacity need is several years in the future, then the present avoided capacity rate should only reflect capacity value starting with the future period when there is a capacity need to avoid. Otherwise, customers would be paying a QF for marginal capacity that is providing no actual benefit to serve their needs for capacity.

Q. IF A UTILITY'S NEXT AVOIDED CAPACITY NEED IS SEVERAL YEARS IN THE FUTURE, WHEN DOES THE QF BEGIN RECEIVING A CAPACITY PAYMENT?

A. Under the levelized Schedule PP rate design, discussed below, the avoided capacity payments are levelized to allow the QF to receive an avoided capacity payment in each year of the contract, as long as an actual capacity need exists at some point within the term of the avoided cost period. More precisely, the QF will receive a levelized capacity rate that takes into account a zero value of capacity in the initial years prior to the utility's first avoidable capacity need, as well as an avoidable capacity value in all subsequent years of the avoided cost period. Put another way, the QF will receive capacity payments during each year of the contract, in order to credit the QF for the future avoided capacity, so long as the utility has an avoidable capacity need within the avoided cost period.

Q. IS RECOGNITION OF THE UTILITIES' NEED FOR CAPACITY IN THIS CALCULATION FAIR TO THE COMPANIES' CUSTOMERS AND TO QFs?

A. Yes, the utilities' customers only pay the QF capacity payments equal to the economic value of the utility's actually avoided capacity cost. It also fair and non-discriminatory to QFs.

Q. WHAT METHOD DO THE COMPANIES RECOMMEND FOR PAYING QFs FOR CAPACITY VALUE?

A. With respect to QF rates, the Companies recognize that traditional methods of paying for dispatchable capacity based on deliverability requirements with after-the-fact adjustments for actual unit performance, are particularly problematic for smaller intermittent QF resources. To overcome these deliverability challenges and the lack of QF dispatchability, the Companies' QF capacity rates are paid on a per-kWh basis across a pre-determined set of seasonal hours that represent the hours most likely to have capacity value, as described later in my testimony. Paying QFs for capacity on a per-kWh basis is consistent with the approach the Companies have historically utilized with respect to QF rate design under prior vintages of Schedule PP.

Q. PLEASE DESCRIBE THE SEASONAL ALLOCATION WEIGHTING THAT IS INCLUDED IN THE DETERMINATION OF THE AVOIDED CAPACITY PAYMENTS.

A. Seasonal allocation places capacity value into the appropriate season of the year that drives the Companies' reliability need for new capacity resource additions. For DEC and DEP, seasonal allocation is now heavily weighted to winter based on the impact of summer versus winter loss of load risk, which has been driven by the volatility in winter peak demand, as well as the growing penetration of solar resources and its associated impact on summer versus winter reserves. As presented in detail in the Solar Capacity Value study conducted by Astrapé Consulting and described in the Companies' 2018 IRPs, 100% of DEP's loss of load risk occurs in the winter and approximately 90% of DEC's loss of load risk occurs in the winter.[16] Thus, DEP's filed rates in this proceeding pay all of its annual capacity value in the winter while DEC's new rates pay 90% of its annual capacity value in the winter and the remaining 10% in the summer period.

Q. PLEASE IDENTIFY THE SPECIFIC HOURS WHEN QFs WILL PROVIDE CAPACITY VALUE.

A. The Companies' Schedule PP capacity rate design offers three distinct pricing periods to accurately reflect the marginal capacity value to customers during each capacity period. The pricing periods offer capacity payments during the PM hours in the summer months of July and August and both AM and PM hours in the

[16] *See* DEC 2018 IRP, at Chapter 9 (Capacity Value of Solar), pages 40-41; DEP 2018 IRP, at Chapter 9 (Capacity Value of Solar), pages 40-41.

winter months of December through March. The highest prices are paid in the early morning winter hours to recognize the greater loss of load risk and greater value of capacity during those hours. The three hourly capacity pricing periods are the same for DEC and DEP and are shown in Figure 1 below. These pricing periods represent the hours of capacity need and thus reflect the value of QF capacity to ensure customers are paying for QF capacity that actually reduces the utilities' needs for future capacity. DEP's higher avoided capacity payment compared to DEC is due to DEP's earlier avoidable capacity need in 2020 versus DEC's first avoidable capacity need in 2026.

Figure 1: Avoided Capacity Rate Design Pricing Periods[17,18]

Capacity Rates																								
Independent Capacity Price Blocks			1. Summer Capacity								2. Winter Capacity (AM)								3. Winter Capacity (PM)					
Company			**DEC**		**DEP**						**DEC**		**DEP**						**DEC**		**DEP**			
10-Yr Rate (cents/KWH)			0.86		0.00						3.99		11.36						1.29		4.87			
DEC / DEP **Hour Ending**	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
Summer (Jul - Aug)																	1.Summer							
Winter (Dec - Mar)							2.Winter (AM)												3.Winter (PM)					

Q. PLEASE EXPLAIN WHY A PERFORMANCE ADJUSTMENT FACTOR, OR "PAF," IS RECOGNIZED IN THE AVOIDED CAPACITY CALCULATION.

A. Given that the utility's avoided fleet resources are occasionally unavailable, it necessarily follows that QFs replacing those resources should not be penalized for experiencing the same level of unavailability typically experienced by the resources it is displacing. The PAF is a simple reliability equivalence multiplier that is

17 The 10-year Rate (cents/kWh) presents the avoided capacity rates set forth in Schedule PP for a distribution-connected QF.

18 Snider DEC/DEP Exhibit 2 provides a larger version of Figure 1 for readability purposes.

included in the avoided capacity rates paid by the Companies' customers to QFs. This multiplier increases the avoided capacity rate paid by customers and received by the QF. The Companies included a 1.05 PAF in the avoided capacity calculation as an adjustment to reflect the reliability equivalence of the Companies' generation fleet. For example, if the avoided capacity rate is $30/MWh, applying a PAF of 1.05 would increase the rate to $31.50/MWh, or increasing the amount paid to the QF for capacity by 5%. The Companies' inclusion of a PAF in calculating avoided capacity value is an example of how Duke's application of the peaker methodology treats QFs on fair and equal footing with utility-owned resources, as contemplated by Act 62.

Q. DOES THE COMPANIES' AVOIDED CAPACITY PAYMENT RATE DESIGN PROVIDE APPROPRIATE PRICE SIGNALS TO ENCOURAGE QF DEVELOPMENT AND APPROPRIATELY PAY QFs FOR THE CAPACITY VALUE THAT THEY PROVIDE?

A. Yes. The avoided capacity payment rate design provides appropriate price signals and incentivizes QFs to maximize output during times when capacity has the most value to the Companies' customers.

V. AVOIDED ENERGY COST CALCULATION AND RATE DESIGN METHODOLOGY

Q. IN GENERAL TERMS, HOW ARE AVOIDED ENERGY COSTS CALCULATED UNDER THE PEAKER METHODOLOGY?

A. In any given hour, a utility will have a variety of units online such as hydro-electric, nuclear, solar, natural gas combined-cycle, coal, natural gas simple-cycle CTs and diesel fuel oil CT resources. These units all have differing variable fuel and operating costs that are considered in order to dispatch them in economic merit order to meet the utility's instantaneous load obligations. To calculate the avoided marginal energy value, two production cost simulations are performed and then compared to each other to determine the value of QF energy. A production cost model simulates the generation commitment and dispatch of the utility's fleet of generating resources needed to meet the Companies' load over the ten-year avoided cost period on an hour-to-hour basis. The first simulation uses IRP models and current market assumptions to establish the "base case" of the estimated variable production costs over the period. The second simulation is identical to the first, but adds a hypothetical 100 MW of no-cost generation to the utility's generating fleet, which is available to the system in every hour of the ten-year period. Adding this hypothetical, no-cost generation to the simulation displaces energy from the marginal units that were operating in the "base case," and as a result, lowers the overall variable production costs relative to the base case. Comparing the hourly production cost associated with the base case relative to the second case with the 100 MW of no-cost generation determines the marginal hourly energy costs that can be avoided over the study period. These marginal avoided costs are then used to calculate the avoided energy rates that leave a customer indifferent between QF purchases and generation provided by the utility.

Q. PLEASE EXPAND ON HOW THE AVOIDED MARGINAL ENERGY COSTS ARE DERIVED.

A. Since the utility commits and dispatches its generation units in an economic merit order, comparing the base case production cost run previously described to the second case with 100 MW of no-cost generation results in the marginal variable production cost savings attributable to 100 MW of incremental no-cost generation. Compared to the base case simulation, the case with the 100 MW of no-cost generation will show savings resulting from reduced fuel consumption, reduced environmental allowance costs and reduced VOM costs. These nominal cost savings can then be converted to a dollar per MWh value by dividing the savings in any given time period by the product of the number of hours in that period multiplied by the 100 MW output of the unit. Once nominal avoided energy costs are determined over the ten-year avoided cost period they are then levelized by time period to produce the avoided energy rate in cents per kWh.

Q. WHAT FACTORS INFLUENCE THE CALCULATION OF THE AVOIDED ENERGY COST RATES?

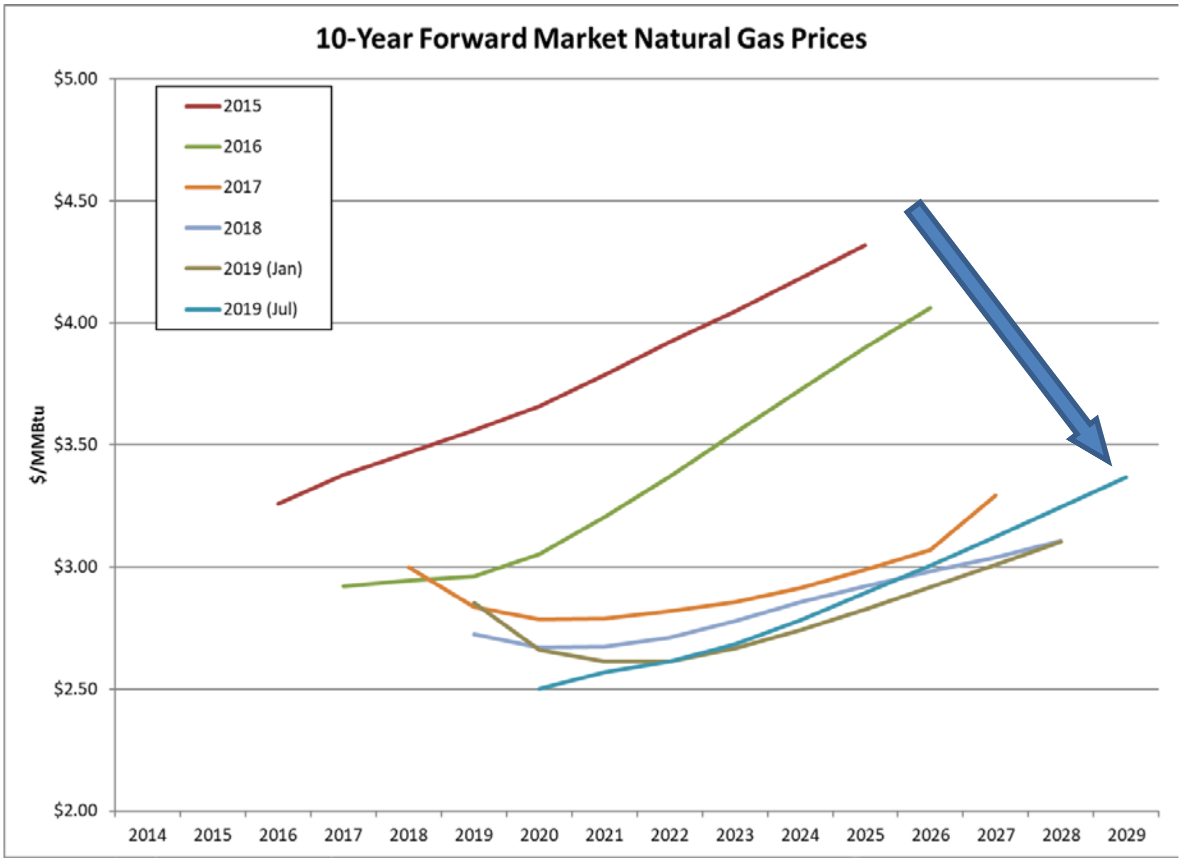
A. A number of factors that drive the avoided cost calculation change over time, including load and energy forecasts, resource mix, unit characteristics, VOM costs, environmental emissions costs, reagent costs and fuel costs. While updating items such as VOM costs, environmental reagent costs, and the relative efficiency of the marginal unit with the most current information all factor into the utility's marginal cost of generation, recent changes in the commodity market price for natural gas represents the most significant change impacting the Companies' avoided costs.

This is because natural gas commodity prices represent the primary driver of the avoidable energy cost since a natural gas-fueled combined-cycle unit or combustion turbine unit is often the marginal resource.

Q. WITH RESPECT TO RECENT CHANGES IN NATURAL GAS COMMODITY PRICES, PLEASE ADDRESS THE SIGNIFICANT MARKET CHANGES THAT HAVE OCCURRED IN RECENT YEARS.

A. It is widely accepted that advancements in shale gas production have significantly changed the natural gas market landscape, drastically reducing the cost of natural gas. Consequently, and by extension, the Companies' and other utilities' cost of avoidable energy production has also declined significantly over the last several years. As shown in Figure 2, which depicts the 10-year forward market natural gas prices dating back to 2015, this transformation has occurred at a rapid pace and has resulted in sustained lower natural gas prices that can be realized through purchases in a liquid and transparent natural gas market.

Figure 2: 10-Year Forward Market Natural Gas Prices (Period 2015 to July 2019)



As I stated, natural gas commodity prices are a significant input into the avoided energy rate calculation. Just as the Companies' customers have benefited from recent significant declines in the future price of natural gas, these declining gas prices have also caused a significant reduction in the Companies' avoided energy costs. For example, the 10-year forward market price of natural gas has declined by approximately 25% between 2015 and 2019, which reduces the Companies' cost of generating electricity and, by extension, their avoided cost.

Q. HOW DO THE COMPANIES OBTAIN AND UTILIZE FORWARD MARKET PRICES OF NATURAL GAS IN CALCULATING AVOIDED ENERGY RATES?

A. The Companies routinely obtain quotes for ten-year natural gas forward prices from financial institutions that readily buy and sell natural gas forward contracts. The Companies also periodically purchase ten-year forward gas positions to demonstrate market liquidity and transparency and to establish the prevailing ten-year forward market prices for natural gas. Importantly, the purchase of ten-year forward natural gas then sets the natural gas commodity prices used as an input to the Companies' resource planning and internal modeling of the cost to operate natural gas generation ten years forward. These prices are similarly utilized in the Companies' avoided cost modeling to establish the indifference point for consumers between utility generated energy and purchased QF energy over the 10-year avoided cost rate period. In addition, these prices are consistently used in internal IRP modeling and are an input to the upcoming 2019 IRP Updates.

Q. PLEASE DESCRIBE THE COMPANIES' AVOIDED ENERGY RATE DESIGN.

A. The marginal energy rate structure includes differentiation of summer, winter and shoulder seasons. The Summer energy season is defined to include June, July, August, and September; the Winter energy season is defined to include December, January, and February; and the Shoulder energy season is defined to include March, April, May, October, and November. The design reflects nine energy pricing periods to reflect the energy value of QF generation during the different time frames. The Schedule PP rate design appropriately compensates QFs for the avoided energy value they create for customers through the incorporation of granular seasonal and hourly rate periods. The nine energy pricing periods and their respective prices are shown in Figure 4 below.

Figure 3: Avoided Energy Rate Design Pricing Periods[19,20]

Energy Rates

Independent Energy Price Blocks	1.Summer Premium Peak (PM)		2.Summer On-Peak (PM)		3.Summer Off-Peak		4. Winter Premium Peak (AM)		5.Winter On-Peak (AM)		6.Winter On-Peak (PM)		7.Winter Off-Peak		8.Shoulder On-Peak		9.Shoulder Off-Peak	
Company	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP	DEC	DEP
10-Yr Rate (cents/KWH)	4.58	3.30	4.48	3.11	2.60	2.68	5.04	3.58	4.61	3.54	4.15	3.42	2.70	2.75	3.39	2.98	2.28	2.26

DEC Energy Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	3.Off												2.On (PM)				1.Premium				2.On (PM)		3.Off	
Winter (Dec-Feb)	7.Off					5.On	4.Premium			5.On	7.Off							6.On (PM)					7.Off	
Shoulder (Remaining)	9.Off						8.On				9.Off						8.On							9.Off

DEP Energy Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	3.Off													2.On (PM)			1.Premium				2.On	3.Off		
Winter (Dec-Feb)	7.Off				5.On (AM)		4.Premium			5.On (AM)		7.Off							6.On (PM)				7.Off	
Shoulder (Remaining)	9.Off					8.On					9.Off							8.On						9.Off

The hourly energy rate periods reflect the concept of including higher-priced periods, called premium peak hours, in the Companies' Winter and Summer seasons. These premium peak hours provide the highest rates to incent generation during these hours when the value of the energy avoided by QF power is greatest for customers. Days with premium-peak and on-peak hours include Monday through Friday, excluding certain holidays. On-peak energy pricing has a defined set of PM hours during the summer period and both AM and PM hours during both the winter and shoulder periods. Off-peak hours within each season include all hours not otherwise defined as premium or on-peak, and include certain holidays. The hourly definitions for the nine pricing periods also vary slightly for DEC and

19 The 10-year Rate (cents/kWh) presents the avoided energy rates set forth in Schedule PP for a distribution-connected QF.

20 Snider DEC/DEP Exhibit 2 provides a larger version of Figure 3 for readability purposes.

DEP to account for the differences in each utility's load profile net of solar generation.

Q. DID THE COMPANIES INCLUDE A TRANSMISSION SYSTEM LINE LOSS CREDIT FOR QFs?

A. Yes. The Companies' avoided cost calculations continue to recognize distribution-connected QF generation's avoidance of transmission system line losses, and therefore, the Schedule PP rates continue to include avoided energy and capacity line loss credits. The Companies also include an avoided loss factor for distribution- and transmission-connected QF generation to recognize the avoidance of generation step-up voltage losses.

Q. DO THE COMPANIES INCLUDE AVOIDED ENVIRONMENTAL COSTS IN THE DEVELOPMENT OF THE AVOIDED ENERGY COST RATES?

A. Yes. As mentioned previously, the Companies' avoided energy cost rates include avoided emission control reagents and allowance costs for sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") based upon the costs actually avoided by the utility. Consistent with PURPA, the Companies have not included more speculative costs, such as avoided carbon dioxide ("CO_2") emission costs that are not actually being avoided by the utility.

Q. DO THE COMPANIES' AVOIDED ENERGY RATE DESIGNS PROVIDE APPROPRIATE PRICE SIGNALS TO ENCOURAGE QF DEVELOPMENT AND APPROPRIATELY PAY QFs FOR THE ENERGY VALUE THAT THEY PROVIDE?

A. Yes. The avoided energy payment rate designs provide sufficient seasonal and hourly granularity and appropriate price signals and incentives for QFs to maximize output during times when energy has the most value to the Companies and their customers.

Q. HOW DO THE COMPANIES APPLY THIS METHODOLOGY FOR CALCULATING AVOIDED ENERGY RATES PAID TO QFs THAT DO NOT QUALIFY FOR THE STANDARD OFFER?

A. The Companies' established practice is to utilize the same peaker methodology in determining the avoided capacity and energy rates offered to both Standard Offer as well as larger QFs not eligible for the Standard Offer. I will refer to these larger QFs not eligible for the standard offer as "non-Standard Offer PPA QFs." The Companies then update the inputs used in the peaker methodology for non-Standard Offer PPA QFs to more accurately reflect the Companies' most current forecast of avoided costs. Going forward, the Companies will also update the generation profile in applying the peaker methodology for non-Standard Offer PPA QFs to apply a solar-specific generation profile for solar QFs to further ensure that the avoided energy rates calculated for non-Standard Offer PPA QFs most precisely equal the Companies' actual avoided cost, consistent with both PURPA and Act 62. Calculating avoided cost for non-Standard Offer PPA QFs in this manner is consistent with Act 62, which prescribes that avoided cost rates offered by an electrical utility to a non-Standard Offer PPA QF "must be calculated based upon the avoided cost methodology most recently approved by the Commission."[21] Additionally, Act 62 allows the avoided cost methodologies approved by the Commission to take into account the specific "geographic location and resource type"[22] of a QF under an approved avoided cost rate methodology.

VI. INTEGRATION SERVICES CHARGE

Q. ACT 62 REQUIRES THE COMPANIES TO TAKE INTO ACCOUNT COSTS AVOIDED OR INCURRED BY THE UTILITIES, INCLUDING ANCILLARY SERVICES PROVIDED BY OR CONSUMED BY SMALL POWER PRODUCERS. HAVE THE COMPANIES INCLUDED ANY ADJUSTMENTS TO THE AVOIDED COST RATES FILED IN THIS PROCEEDING TO ACCOUNT FOR MEASURABLE COSTS OF INTEGRATING INTERMITTENT SOLAR QF POWER?

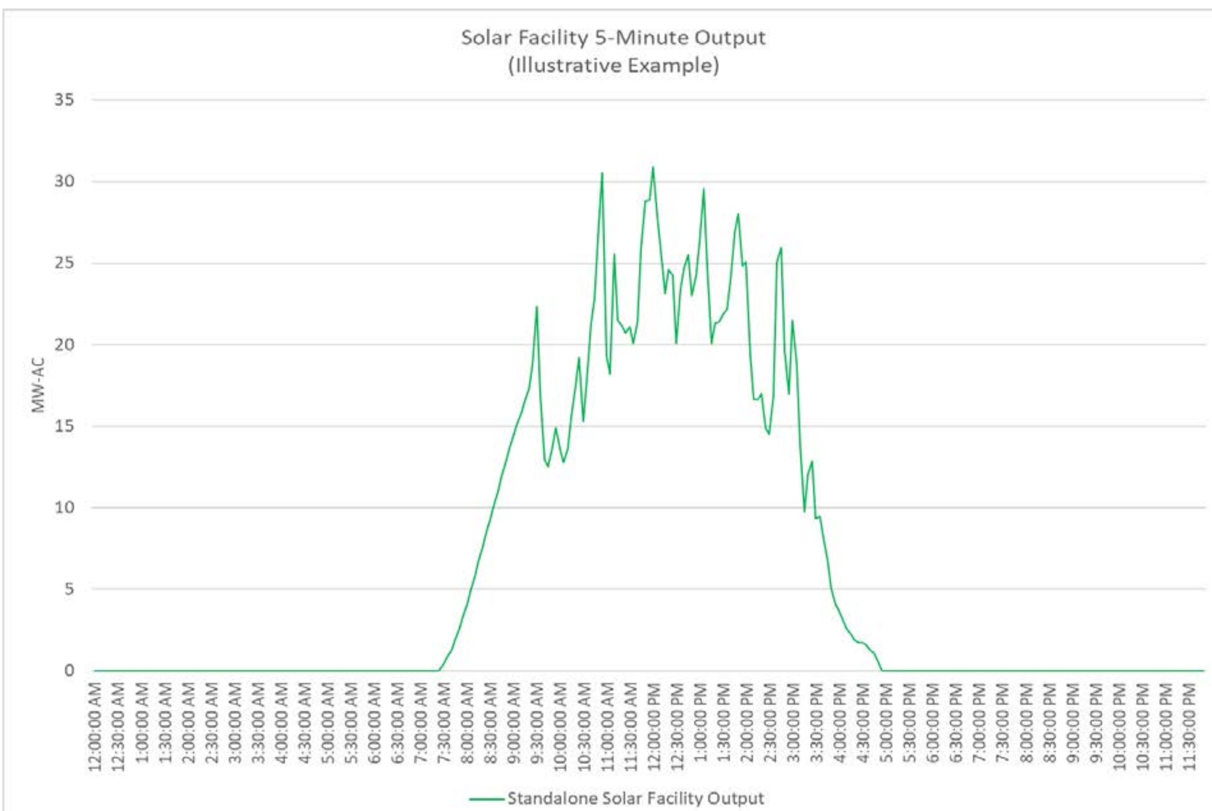
A. Yes, as I previously mentioned, the Companies included a specific measurable Integration Services Charge for intermittent solar generation.

[21] S.C. Code Ann. § 58-41-20(C).
[22] S.C. Code Ann. § 58-41-20(B)(3).

Q. PLEASE EXPLAIN HOW INTEGRATING INTERMITTENT SOLAR RESOURCES IMPACTS THE OPERATIONS OF THE GENERATION SYSTEM AND REQUIRES THE COMPANIES TO INCUR INCREASED ANCILLARY SERVICES COSTS.

A. To meet the Companies' obligation to provide reliable electric service to their respective customers, DEC and DEP must dispatch their generation fleet resources to meet real-time load on a moment-to-moment basis. As shown in the illustrative example presented in Figure 4 below, the energy output from solar resources is variable; it can unexpectedly and rapidly drop-off or ramp-up in real-time, thereby increasing uncertainty in day-ahead, hourly, and sub-hourly projections for fleet operations.

<u>Figure 4: Uncontrolled Solar-Only Facility 5-Minute Output</u>



This additional uncertainty and volatility from intermittent resources requires the Companies to carry additional operating reserves, which are the real-time system resources required to balance and regulate the system on an hourly and sub-hourly basis. Operating reserves are specifically a type of "ancillary service." Ancillary services are defined as services necessary to support capacity and the transmission of energy from resources to loads while maintaining reliable operation of the transmission system. Thus, these operating reserves, or ancillary services, are provided by reserving additional dispatchable conventional fleet resources to ensure that sufficient operational flexibility is available to respond in real-time to rapid changes in solar output. Additionally, ensuring that sufficient operating reserves are available is also required to maintain compliance with North American Electric Reliability Corporation ("NERC") bulk electric system balancing and reliability standards. The need for increased real-time system operating reserves to reliably integrate increased levels of uncontrolled solar generation results in additional operating costs relative to a dispatchable or baseload generation source.

Q. HOW DOES SOUTH CAROLINA LAW REQUIRE THE COMPANIES TO CONSIDER THESE ANCILLARY SERVICE IMPACTS, AND RESULTING COSTS, FOR INTEGRATING INTERMITTENT SOLAR INTO THE GENERATION SYSTEM?

A. In enacting Act 62, the South Carolina General Assembly directed the Commission, and by extension the Companies, to consider ancillary services in the methodology used in establishing avoided cost rates.[23] Section 58-41-20(B)(3) explicitly requires the utilities' avoided cost methodology to account for costs avoided or incurred by the electrical utility, *including ancillary services provided by or consumed by small power producers*. Accordingly, the Companies are charging solar QFs for the projected costs that DEC and DEP and their customers will incur to provide the additional ancillary services required to integrate uncontrolled solar QFs.

Q. DOES ACT 62'S REQUIREMENTS THAT THE COMPANIES CONSIDER ANCILLARY SERVICE IMPACTS AS WELL AS QF RESOURCE TYPE IN CALCULATING AVOIDED COSTS ALIGN WITH PURPA?

A. Yes. Act 62's requirement that the Companies account for ancillary services impacts and the QF's resource type helps to ensure that avoided cost rates meet PURPA's objective of appropriately valuing the Companies' incremental costs of alternative energy to be avoided from purchasing power from a particular QF. Even more importantly, this requirement ensures that PURPA's objective of customer indifference is achieved by placing the increased ancillary services costs resulting from the integration of intermittent QFs on the cost causer—*i.e.* the uncontrolled solar small power producer—rather than on the Companies' customers.

[23] S.C. Code Ann. § 58-41-20 (B)(3).

Q. HOW DID THE COMPANIES QUANTIFY THE INCREASED OPERATING COSTS THAT THEY INCUR TO RELIABLY INTEGRATE THE UNCONTROLLED SOLAR QF GENERATION ON THEIR RESPECTIVE SYSTEMS THAT YOU DESCRIBE ABOVE?

A. In late 2017, Duke commissioned Astrapé Consulting to analyze the impacts of integrating solar into the Companies' systems at varying solar penetration levels and to quantify the cost of utilizing the DEC and DEP fleets to provide the additional operating reserves or generation "ancillary services" needed to reliably integrate the various levels of intermittent solar generation. Mr. Nick Wintermantel of Astrapé Consulting is testifying in this proceeding as an expert witness and his testimony reviews the methodology and results of the Solar Ancillary Service Study conducted for DEC and DEP.

Q. WHAT FACTORS INFLUENCE THE INTEGRATION COSTS FOR THE DEC AND DEP SYSTEMS?

A. As discussed in Duke Witness Nick Wintermantel's testimony, the cost to carry additional ancillary services required to reliably integrate solar generation into a utility's system is driven by several factors. In general terms, these factors include the characteristics and make-up of dispatchable generation resources within a utility's existing system, the underlying cost of the fossil fuels used by those resources, the nature of the utility's load profile and the amount of solar resources on the system.

Q. PLEASE GENERALLY DESCRIBE THE PENETRATION LEVELS OF SOLAR STUDIED.

A. As discussed in Duke Witness Brown's testimony, both Companies already have a significant amount of solar resources installed on their systems. In addition to studying a baseline case of 0 MW of installed solar, Astrapé evaluated projected solar penetration levels in year 2020 based on the expected amounts of solar that are already operating or will be interconnected to the Companies' systems pursuant to existing renewable energy programs (such as Act 236 and PURPA purchases) and the first tranche of DEC's and DEP's competitive procurement of renewable energy ("CPRE") program as well as other solar programs (large customer Green Source program and community solar) implemented pursuant to North Carolina House Bill 589 enacted in 2017. As further discussed by Duke Witness Wintermantel and identified in the Solar Ancillary Service Study, the Companies requested Astrapé study three different solar penetration levels: "Existing plus Transition," "Tranche 1," and "+1,500 MW." The "Existing plus Transition" is the most conservative of the solar penetrations studied and reflects 2020 solar installations of 840 MW and 2,950 MW in DEC and DEP, respectively. The next penetration level studied (called "Tranche 1") assumes 1,520 MW in DEC and 3,110 MW in DEP, which, at the time of the study, represented the amount of solar expected to be installed as a result of Tranche 1 of the CPRE Program (and includes "Existing plus Transition" solar). The final penetration level studied (called "+1,500 MW") assumes 3,020 MW in DEC and 4,610 MW in DEP and was studied to assess a potential, future high penetration scenario.

These various capacity levels were selected to allow the ancillary service impacts to be measured across a broad range of solar penetration levels.

Q. WHAT LEVEL OF STUDIED SOLAR PENETRATION HAVE THE COMPANIES USED TO QUANTIFY THE INTEGRATION SERVICES CHARGE?

A. The solar Integration Services Charge is based upon the "Existing plus Transition" level of solar penetration, which represents the solar penetration the Companies expect to be installed on the DEC and DEP systems by 2020. Using either of the higher solar penetration levels studied would have resulted in a higher Integration Services Charge as identified in the study.

Q. WHAT ARE THE VALUES FOR THE INTEGRATION SERVICES CHARGES INCLUDED IN YOUR AVOIDED COST RATES FOR DEC AND DEP?

A. Separate solar Integration Services Charges are included in Schedule PP for DEC and DEP. For DEC the charge is $1.10/MWh. For DEP, the charge is $2.39/MWh.

Q. WILL THE INTEGRATION SERVICES CHARGES BE UPDATED?

A. Yes. The Integration Services Charge within a solar provider's contract will be updated biennially at each avoided cost proceeding. This will allow for the uniform application of the charge and will account for changes in market factors impacting the cost of integration over time.

Q. WHICH SOLAR GENERATORS WILL INCUR THE SOLAR INTEGRATION SERVICES CHARGE?

A. As it relates to this proceeding, all solar QFs selling power to DEC and DEP under the Schedule PP avoided cost rates filed in this proceeding will be subject to this Integration Services Charge. The Companies are not proposing to apply this charge retrospectively to existing solar resources or to those solar resources that have established contracts under previously-authorized long-term fixed rates. As existing contracts with solar QFs expire, however, any new solar contracts, or contract renewals, would include such a provision. As such, the Companies plan to update the Integration Services Charge as a normal part of future avoided cost filings to account for changes in the previously-mentioned factors such as solar penetration levels, prevailing fuel prices and the makeup of the Companies' future resource portfolios. Thus, over time, as existing contracts expire and new contracts are executed, this Integration Services Charge will apply to all solar providers uniformly.

Q. HOW ARE THE COMPANIES' CUSTOMERS IMPACTED IF INTEGRATION COSTS ARE NOT INCLUDED IN THE AVOIDED COST TARIFF AND NOT CHARGED TO SOLAR QFs?

A. If an adjustment is not made to the avoided cost tariff to account for these specific operational costs driven by the integration of intermittent solar resources, then the Companies' customers bear this cost, which is recovered in the annual fuel cost proceeding. Failure to properly charge these costs to the cost causer – *i.e.*, the intermittent solar QF – would unfairly burden the Companies' customers with increased costs and would violate the ratepayer indifference objective underlying PURPA. Additionally, applying this charge to the proper cost causer furthers the General Assembly's charge in Act 62 that decisions made under Section 58-41-20 strive to reduce the risk placed on the using and consuming public.

Q. WILL THE SOLAR INTEGRATION SERVICES CHARGE COLLECTED FROM SOLAR GENERATORS BE CREDITED TO CUSTOMERS IN FUTURE FUEL PROCEEDINGS TO OFFSET THE INCREASED FUEL AND FUEL-RELATED COSTS ASSOCIATED WITH INTEGRATING SOLAR RESOURCES?

A. Yes, it will be.

Q. CAN SOLAR QFs UTILIZE ENERGY STORAGE TO MITIGATE THE INCREASED ANCILLARY SERVICES THAT WOULD OTHERWISE BE REQUIRED BY THE COMPANIES, AND AS A RESULT, AVOID THE SOLAR INTEGRATION SERVICES CHARGE?

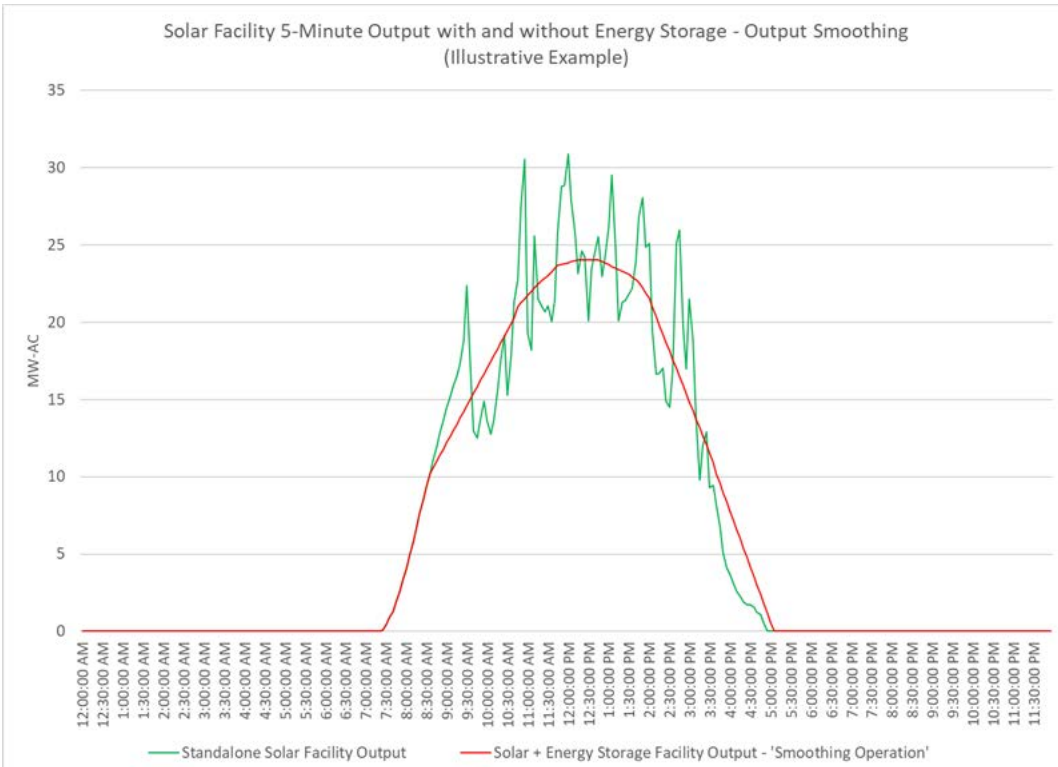
A. Potentially. As I explain further below, a solar QF that integrates energy storage equipment or otherwise commits to operate as a "controlled solar generator" has the potential to not impose these increased operating costs on the Companies' systems and, therefore, would appropriately not be assigned the integration costs. It is worth noting that the mere existence of energy storage equipment integrated with a solar QF does not guarantee that the QF will be considered a controlled solar generator and avoid the Integration Services Charge. The question of whether the QF can use energy storage to mitigate/avoid the utilities' need to carry additional operating reserves must be reviewed on a case-by-case basis. Energy storage equipment can be dispatched in various ways, not all of which reduce intermittency, or reduce intermittency significantly enough to impact the utilities' need for additional operating reserves. However, in recognition that the possibility exists for a solar QF to use energy storage in a manner that could significantly reduce or eliminate the cost of the additional ancillary services, the Companies will not impose the Integration Services Charge on a solar QF that designs its facility—including through integration of energy storage equipment—and contractually commits through a negotiated PPA to operate as a controlled solar generator.

Q. CAN YOU NOW ILLUSTRATE HOW A SOLAR QF THAT INTEGRATES ENERGY STORAGE EQUIPMENT COULD OPERATE TO MATERIALLY REDUCE OR ELIMINATE ANCILLARY REQUIREMENTS AND TO ENABLE THE SOLAR GENERATOR TO OPERATE AS A CONTROLLED SOLAR GENERATOR TO AVOID THE INTEGRATION SERVICES CHARGE?

A. My Figure 4 above presents an illustrative example of the 5-minute output of a standalone 40 MW solar facility operating on a winter day in the Carolinas. The intra-hour volatility of the facility's output, which can be caused by phenomenon such as intermittent cloud cover, is one of the main reasons that the Companies are required to carry ancillary services that are the driver for the Integration Services Charge.

My Figure 5 below demonstrates how energy storage equipment that is integrated with a solar QF could be operated to smooth its delivered energy output (red line) by charging the battery when solar output quickly spikes and discharging the battery when solar output quickly drops.

<u>Figure 5 – Controlled Solar Facility 5-Minute Output Operated to Smooth the Facility's Output</u>



In order to avoid the Integration Services Charge, a solar facility with energy storage equipment would need to demonstrate that it could eliminate, or substantially reduce, the intra-hour volatility that is associated with a standalone solar facility as shown in Figure 5.

Q. DO YOU BELIEVE THAT THE INTEGRATION SERVICES CHARGE IS FAIR TO THE SOLAR QF GENERATORS AND THE COMPANIES' CUSTOMERS?

A. Yes. I believe that the Integration Services Charge properly attributes these costs to the appropriate cost causer, as opposed to imposing additional costs on the Companies' customers, and that the Companies' have reasonably and fairly implemented the charge to intermittent solar QFs on a prospective basis. The Companies also support a QF that designs its facility and commits to operate as a controlled solar generator being allowed to avoid the Integration Services Charge.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Testimony of Glen A. Snider
Confidential DEC Exhibit 1

Duke Energy Carolinas, LLC

(Filed Under Seal)

Testimony of Glen A. Snider
Confidential DEP Exhibit 1

Duke Energy Progress, LLC

(Filed Under Seal)

Snider Exhibit 2:
Energy Rate Design and Capacity Rate Design

Figure 1: Avoided Capacity Rate Design Pricing Periods

Capacity Rates

Independent Capacity Price Blocks	1. Summer Capacity		2. Winter Capacity (AM)		3. Winter Capacity (PM)	
Company	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**
10-Yr Rate (cents/KWH)	0.86	0.00	3.99	11.36	1.29	4.87

DEC / DEP Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jul - Aug)																	1.Summer	1.Summer	1.Summer	1.Summer				
Winter (Dec - Mar)							2.Winter (AM)	2.Winter (AM)	2.Winter (AM)										3.Winter (PM)	3.Winter (PM)	3.Winter (PM)			

Figure 3: Avoided Energy Rate Design Pricing Periods

Energy Rates

Independent Energy Price Blocks	1.Summer Premium Peak (PM)		2.Summer On-Peak (PM)		3.Summer Off-Peak		4. Winter Premium Peak (AM)		5.Winter On-Peak (AM)		6.Winter On-Peak (PM)		7.Winter Off-Peak		8.Shoulder On-Peak		9.Shoulder Off-Peak	
Company	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**	**DEC**	**DEP**
10-Yr Rate (cents/KWH)	4.58	3.30	4.48	3.11	2.60	2.68	5.04	3.58	4.61	3.54	4.15	3.42	2.70	2.75	3.39	2.98	2.28	2.26

DEC Energy Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	2.On (PM)	2.On (PM)	2.On (PM)	2.On (PM)	1.Premium	1.Premium	1.Premium	1.Premium	2.On (PM)	2.On (PM)	3.Off	3.Off
Winter (Dec-Feb)	7.Off	7.Off	7.Off	7.Off	7.Off	5.On	4.Premium	4.Premium	4.Premium	5.On	7.Off	7.Off	7.Off	7.Off	7.Off	7.Off	7.Off	6.On (PM)	6.On (PM)	6.On (PM)	6.On (PM)	6.On (PM)	7.Off	7.Off
Shoulder (Remaining)	9.Off	9.Off	9.Off	9.Off	9.Off	9.Off	8.On	8.On	8.On	8.On	9.Off	9.Off	9.Off	9.Off	9.Off	9.Off	8.On	8.On	8.On	8.On	8.On	8.On	8.On	9.Off

DEP Energy Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Summer (Jun-Sep)	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	3.Off	2.On (PM)	2.On (PM)	2.On (PM)	1.Premium	1.Premium	1.Premium	1.Premium	2.On	3.Off	3.Off	3.Off
Winter (Dec-Feb)	7.Off	7.Off	7.Off	7.Off	5.On (AM)	5.On (AM)	4.Premium	4.Premium	4.Premium	5.On (AM)	5.On (AM)	7.Off	7.Off	7.Off	7.Off	7.Off	7.Off	7.Off	6.On (PM)	6.On (PM)	6.On (PM)	6.On (PM)	7.Off	7.Off
Shoulder (Remaining)	9.Off	9.Off	9.Off	9.Off	9.Off	8.On	8.On	8.On	8.On	8.On	9.Off	9.Off	9.Off	9.Off	9.Off	9.Off	9.Off	8.On	8.On	8.On	8.On	8.On	8.On	9.Off